Via E-mail

Ms. Cynthia Kaleri
Branch Chief, Air Permits, Monitoring & Grants
U.S. EPA Region 6, 6PD
1201 Elm Street, Ste. 500
Dallas, TX 75270

Re: § 112(g) Determination Request
Bluewater Texas Terminal LLC ("BWTX")

October 25, 2019

Dear Ms. Kaleri:

BWTX hereby submits a supplement to its pending § 112(g) Determination Request.

I certify that, based on information and belief formed after reasonable inquiry, that the statements and information contained in these documents are true, accurate and complete.

If you have any additional questions regarding this application, please contact Ms. Chaitali Dave of Phillips 66 Company at chaitali.r.dave@p66.com or 832-765-1069; or Dr. Jesse Lovegren of DiSorbo Consulting, LLC, at jlovegren@disorboconsult.com or 512-961-4471.

Yours,

D Farris

David Farris
Vice President
BWTT

Enclosure

Supplementary Materials

On August 15, 2019, BWTX submitted a response ("the response") to EPA's July 19, 2019, completeness determination for its § 112(g) determination request. The present submission is a supplement to the response, containing information that BWTX understands to be relevant to EPA's review of the § 112(g) determination request.

Supplemental information presented below is arranged topically, following the numbering scheme in the July 19, 2019, completeness determination.

Page references in square brackets refer to the pagination of electronic PDF files as originally submitted to EPA, and otherwise refer to the pagination indicated on the page referred to, if any.

Items 1(a), 10, 12

Estimated hydrocarbon emission rates corresponding to each sample appear in Attachment 5 [p. 99] of the response, along with estimated mass fractions for each identified HAP species. The maximum total vapor phase HAP weight fraction in any of the samples is 4.4% (Sample 5). Speciated emission rates associated with a sample are obtained by multiplying the sample-specific hydrocarbon emission rate by the sample-specific vapor phase weight fraction for a species.

Long-term emission rates (tpy)

Sample	Hexane	Benzene	Toluene	m-Xylene	p-Xylene	o-Xylene	Ethylbenzene	Styrene	Xylenes
1	376.54	40.01	22.36	11.41	5.77	2.59	1.29	0.12	19.77
2	224.83	4.22	9.46	3.35	4.07	1.53	1.24	0.00	8.95
3	351.97	34.51	27.61	4.73	3.35	1.77	2.66	0.00	9.86
4	403.90	25.81	16.78	4.77	3.61	1.81	1.42	0.00	10.19
5	343.11	32.68	31.72	7.11	4.13	2.11	2.02	0.00	13.36
MAX	**403.90**	**40.01**	**31.72**	**11.41**	**5.77**	**2.59**	**2.66**	**0.12**	**19.77**

Short-term emission rates (lb/hr)

Sample	Hexane	Benzene	Toluene	m-Xylene	p-Xylene	o-Xylene	Ethylbenzene	Styrene	Xylenes
1	239.62	25.46	14.23	7.26	3.67	1.65	0.82	0.07	12.58
2	142.36	2.67	5.99	2.12	2.58	0.97	0.78	0.00	5.67
3	223.02	21.86	17.49	3.00	2.12	1.12	1.69	0.00	6.25
4	250.62	16.01	10.41	2.96	2.24	1.12	0.88	0.00	6.33
5	216.73	20.64	20.03	4.49	2.61	1.34	1.27	0.00	8.44
MAX	**250.62**	**25.46**	**20.03**	**7.26**	**3.67**	**1.65**	**1.69**	**0.07**	**12.58**

Items 1(c), 13

No emissions-generating maintenance activities will occur at the facility other than the floating hose-replacement activity identified on p. 26 [27] of the response.

Item 1(d)

BWTX intends to submit supplementary information under separate cover.

Item 2

Definitions of regulatory terms in MACT Y are excerpted on p. 5-1 [29] of the § 112(g) determination request. The proposed facility is not subject to MACT Y requirements because does not qualify as a "terminal." The definition of "terminal" includes the term "structure," which does not include a floating buoy based on its definition in *Oxford English Dictionary* ("*a building or edifice of any kind, esp. a pile of building of some considerable size and imposing appearance.*")

Table 5-1 [pp. 32–36] of the § 112(g) determination request lists all of the offshore loading facilities believed to be in existence at the time of the MACT Y rulemaking. Facilities loading crude oil were nearshore operations for handling relatively small volumes for coastwise trade. None of these facilities, which were analyzed in detail in BWTX's earlier submittals, were used for the export of crude oil. Such exports were generally prohibited under Section 103 of the Energy Policy and Conservation Act of 1975,[1] which was repealed on December 18, 2015.[2] Therefore, the source category corresponding to BWTX's proposed facility (crude oil export facility) could not have existed at the time MACT Y was developed, and is not reasonably covered by the defined terms in MACT Y.

Item 6

The three terminals mentioned in this item (Phillips 66 Rodeo, CA; Chevron, Richmond, CA; Alyeska Valdez, AK) use a vapor combustor or vapor recovery unit as a control device because space limitations and safety/operability considerations do not preclude them as options. These are shoreside or near-shore terminals which employ docks, whether along the shoreline or along a short causeway. The proposed BWTX facility is not of the causeway type, as discussed in Section 3 [pp. 18–22] of the application.

The proposed CALM buoy is not physically capable of housing the equipment necessary for operation of a vapor combustion unit. Therefore, use of a VCU would require construction of a separate structure (i.e., an offshore platform) outside of the area to be avoided (ATBA), at least 1350 meters from the buoy (cf. Appendix A [p. 70] of application). The necessary closed vent system implied by such an arrangement would present safety and operability challenges which have been detailed on pp. 18–20 [19–21] of the response. No such system is in operation in the United States.

The proposed CALM buoy is not physically capable of housing the equipment necessary for operation of a vapor recovery unit. Therefore, use of a VRU would require construction of a separate structure (i.e., an offshore platform) outside of the area to be avoided (ATBA), at least 1350 meters from the buoy (cf. Appendix A [p. 70] of application). The necessary closed vent system implied by such an arrangement would present safety and

---

[1] P.L. 94-163 (89 Stat. 871, 877). Dec. 22, 1975.
[2] P.L. 114-113 (129 Stat. 2242, 2987). Dec. 18, 2015.

operability challenges which have been detailed on pp. 18–20 of the response. No such system is in operation in the United States.

Item 8

The response provided technical and environmental considerations for not using a platform, whether new or refurbished. Additional information is incorporated below for each scenario considered.

New Platform

Vol. II, Sec. 2 of the Deepwater Port license application includes an evaluation of design alternatives, one of which was the use of a dual berth, fixed platform design. Pp. 23–25 of the response included a summary table expanding upon Table 2-24 (p. 2-52) of the license application. Additional considerations from the evaluation of design alternatives in the license application are excerpted below:

> DWP Alternative 2: Fixed Platform Design
>
> The design and functionality of a fixed platform for the offshore loading of vessels is similar to that of a fixed dock or terminal used at inland port facilities. The use of an offshore fixed platform for the loading of VLCCs would require an approximate 25,000 square ft. platform equipped with marine loading arms and dock supporting infrastructure, mooring dolphins, and catwalks. The offshore fixed platform would be connected to shore-based facilities using subsea/offshore pipeline infrastructure for the loading of vessels.
>
> The fixed offshore platform would be supported by multiple large-diameter pile arrangements installed on the seafloor and installed to sufficient depths to ensure structural integrity. Additionally, the mooring of vessels at a fixed platform requires the installation of mooring dolphins and catwalks to safely secure vessels during loading operations. Below is a general overview of the processes required for the loading of vessels at an offshore fixed platform.
>
> - Vessels would approach the offshore fixed platform.
> - Support vessels are used to safely navigate vessels for mooring at the fixed platform.
> - A combination of platform personnel and support vessels aid in the mooring of the vessel.
> - Marine loading arms are connected to the vessel manifold.
> - Fixed platform personnel operate valves for the transfer of crude oil to the vessel.
> - Once the vessel is fully loaded, marine loading is disconnected from the vessel.
> - A combination of platform personnel and support vessels aid in the unmooring of the vessel.
> - Support vessels are used to safely navigate vessels away from the fixed platform.

The fixed offshore platform is a manned system requiring the use of onsite personnel for operations. Additionally, a fixed platform requires the use of support vessels which are required for vessel approach, mooring/unmooring, and departure product hose connection and disconnection. As such, the use of a fixed platform requires the transport of onsite personnel to and from the location of the offshore fixed platform and the necessary facilities to support the health and safety of onsite personnel.

The onsite construction of a fixed platform is estimated to require 4 months. This includes the transport of the prefabricated materials to the designated location, installation of platform supporting piles, mooring dolphins, installation marine loading arms, and connection to sub-sea pipeline infrastructure.

DWP Design Criteria 1 - Minimizes the Potential for Interference with Natural Processes

Natural processes such as wind, waves, and currents exert forces on and below the water surface. The minimization of the overall structures above and below the water surface results in minimal interference with forces exerted by natural processes. The Two Buoy System Design is smaller than that of the Dual Berth Fixed Platform Design. Additionally, the Two Buoy System Design would be supported in location by tension chains designed to allow for movement with natural forces. A rigid fixed dock platform requires the installation of multiple rigid pile structures both above and below the water surface. Additionally, vessels moored to a SPM buoy system are not sensitive to directional changes of wind, waves, and currents as the vessel is free to “weather-vane” around the SPM buoy to stay head-on during various weather, wind, wave, and current forces.

DWP Design Criteria 2 – Berth Availability

Berth availability and ability to safely moor a vessel at an offshore DWP is dependent on the environmental conditions such as weather, winds, and waves as well as the DWP’s design capabilities for accommodating the safe mooring of vessels in such conditions. Variations of wind and currents occur seasonally within the Gulf of Mexico. As such a DWP system that allows for the accommodation for various conditions allows for the safe mooring of vessels, and thereby greater efficiency and utilization of the DWP. The use of SPM buoy systems allows for vessels to “weather-vane” around the buoy to stay head-on during various weather, wind, wave, and current forces, whereas a fixed dock structure requires the vessels be positioned in a designated manner to allow for loading operations. The ability of the SPM buoy systems to accommodate for the various offshore conditions allows for greater berth availability.

DWP Design Criteria 3 – Personnel Required for Operation

An SPM buoy system is an unmanned system remotely operated from a land-based facility. The use of support vessels for the SPM buoy operations is limited to the mooring/unmooring and product hose connection and disconnection. The fixed offshore platform is a manned system requiring the use of onsite personnel for operations. Additionally, a fixed platform requires the use of support vessels for the vessel approach, mooring/unmooring, and departure product hose connection and disconnection. As such, the use of a fixed platform requires the transport of onsite personnel to and from the location of the offshore fixed platform and the necessary facilities to support the health and safety of onsite personnel. The optimal DWP design would be one that minimizes potential safety hazards through the minimization of the number of onsite personnel required at the DWP during operations. As such, the use of an SPM buoy system for the loading of vessels reduces operational dependency of onsite personnel and support vessels, thereby minimizes potential health and safety exposures.

DWP Design Criteria 4 – Length of Construction Schedule

A longer onsite construction timeframe results in greater disturbance of the marine environment and impacts to benthic habitats, underwater noise disturbance, suspension of sediments, and prolonged impacts to water quality. The onsite construction of a fixed platform is estimated to require 4 months whereas the onsite construction of two SPM buoy systems is estimated to require 2 months. As such, the construction of the SPM buoy systems minimizes the length of onsite construction required for the installation of a DWP.

DWP Design Criteria 5 – Maintenance Requirements

The maintenance of a fixed berth will be greater than an SPM buoy due to its multiple fixed components such as loading arms, valves, and controls equipped on the deck of the platform. The greater amounts of maintenance associated with an offshore platform require prolonged hazard exposure to personnel in an offshore environment, thereby presenting significant safety concerns.

DWP Design Criteria 6 – Seabed and Above Water Footprint

The SPM buoy system would provide a smaller footprint on the seabed and above water than a fixed platform which in turn would result in less environmental impacts. Each SPM buoy system would consist of multiple components including a PLEM, a floating buoy, mooring hawsers, floating hoses, and sub-marine hoses. The PLEM system would be an approximate 65 ft. by 34 ft. steel frame structure positioned directly beneath the proposed SPM buoy system and would be anchored directly to the seafloor with anchor piles. Above the water, each SPM will be approximately 1,000 square ft. and approximately 25 ft. in height. A fixed platform with the ability to load VLCCs would require an approximate 25,000 square ft. platform with mooring dolphins with catwalks connecting each structure. Additionally, a fixed platform would likely require a helipad to transport personnel to and from the structure for maintenance and operations. As such, for the purposes of simultaneously loading VLCCs in an offshore environment, the use of SPM buoy systems requires less surface area, subsurface area, and impacts to the seafloor.

DWP Design Criteria 7 – Accidental Collision Damage

Based on conversations with major SPM buoy venders, SPM buoys under service contracts experience minor, if any, damage as a result of operations. An SPM buoy system is anchored to the seafloor by chains which are set at appropriate tensions to allow for the flexibility and movement of the SPM buoy system in response to various offshore conditions. A fixed platform is supported by pile structures which are rigid structures. In the situation of an accidental collision, the SPM buoy design allows for the dissipation of forces exerted by the vessel whereas rigid structures associated with a fixed platform absorb forces. As such, damages as a result of an accidental collision would be less for an SPM buoy than that of a fixed platform.

…

Based on the results of the Tier V – Deepwater Port Design Alternatives analysis, as presented in Table 2-24, the use of the SPM buoy systems alternative was determined to be the most practicable DWP design alternative to be carried forward.

Refurbished Platform

As noted on p. 22 of the response, BWTX's Deepwater Port license application must include an evaluation of the feasibility of using refurbished OCS components, including existing platform infrastructure. Details of this evaluation are contained in Vol. II, Sec. 2 of the license application, relevant parts of which read as follows:

…Tier III of the alternatives analysis investigates the feasibility for utilizing existing offshore infrastructure to minimize impacts to the maximum extent practicable while fulfilling Project objectives and the purpose and need.

Of the existing offshore infrastructure located within the Corpus Christi area, the use of existing underutilized pipelines and or platform structures was analyzed to determine the technical feasibility for the use for the proposed Project. The following criteria were used for analysis of existing offshore pipelines and or platform infrastructure.

Existing Offshore Platform Infrastructure Criteria

Existing Platform Criteria 1: Existing platform is located within water depths of approximately 85 ft. to allow for the direct and full loading of VLCCs.

Existing Platform Criteria 2: Existing platform should be sited to not interfere with other existing offshore operations. As such, the existing platform structure should be a minimum of 1 statute mile from any other active or abandoned platforms.

Existing Platform Criteria 3: Existing platform location should be sited such that the required connecting pipeline infrastructure should not be routed across existing anchorage areas or safety fairways.

…

Failure to identify either existing offshore platform or pipeline infrastructure with the ability to fulfill the above described criteria indicates the need for the installation of new infrastructure. The following sections discuss the analysis of existing offshore platform and pipeline infrastructure and their ability to fulfill the siting criteria listed above.

…

An analysis of existing offshore platform infrastructure was conducted within the Corpus Christi area. This analysis included a review of abandoned platform infrastructure. A total of 7 existing offshore platforms were identified within the 50-mile radius area previously described as the Corpus Christi area … Of the platforms identified, 2 are located within water depths greater than 85 ft. and are greater than 1 mile away from other offshore platforms. However, the platforms identified would require the installation of pipeline infrastructure across existing safety fairways. Additionally, the distance of the identified platforms to the shoreline is in excess of 50 miles, thereby requiring the installation of long distances of offshore pipeline infrastructure. For the described reasons, the use of existing offshore platform infrastructure was not considered technically feasible for the proposed Project.

Item 9

Pages [57–64] of the response are the requested lightering analysis. The results of the analysis may be condensed into summary tables, which are appended below. The analysis prepared for the Deepwater Port license application considered VOC and NO_X emissions, and the assumed vapor pressure and molecular weight was based on a generic, RVP 9.5 crude oil rather than that calculated based on the five samples.

The original analysis has been revised using the maximum hydrocarbon emission rates provided in response to Items 10 and 12 of the completeness determination. The original analysis has also been revised to indicate HAP emissions based on the HAP weight fraction of 4.4% noted above, and also to include GHG emissions.

Lightering Analysis (Summary)
Bluewater Texas Terminal LLC

Activity	Pollutant	Emission Rate (tpy, SPM scenario)	Emission Rate (tpy, Lightering scenario)
Vessel Engines	NO_X	1120	6008
Vessel Engines	CO	307	1431
Vessel Engines	SO_2	45	210
Vessel Engines	Particulate	39	182
Vessel Engines	VOC	39	183
Vessel Engines	GHG	143	667
Vessel Engines	HAP	1	3
Loading Emissions (uncontrolled)	VOC	14456	14601
Loading Emissions (uncontrolled)	HAP	636	642
Loading Emissions (uncontrolled)	H_2S	2	2
Loading Emissions (controlled)	VOC	0	143
Loading Emissions (controlled)	HAP	0	6
Loading Emissions (controlled)	SO_2	0	4
Loading Emissions (controlled)	NO_X	0	29
Loading Emissions (controlled)	CO	0	21
Loading Emissions (controlled)	Particulate	0	2
Loading Emissions (controlled)	GHG	0	33660

Supporting Calculations (Vessel Emissions for Lightering)
Bluewater Texas Terminal LLC

Vessel Engine Emission Factors

Pollutant	Emission Factor (lb/hp-hr)
NOx (VLCC and Aframax)	0.0237
NOx (Tug)	0.0158
CO	0.0055
SO_2	0.0008
$PM/PM_{10}/PM_{2.5}$	0.0007
VOC	0.0007
CO2e	0.0026
HAP	0.000011

Maximum Engine Loads

Vessel Type	Maximum Load (kW)	Maximum Load (hp)
VLCC	26000	34866
Aframax	13000	17433
Tractor Tug		10000

Operating Levels

Lightered Load (MBbl)	Total Throughput (MBbl/yr)
500	384000

Vessel Activities Per Lightered Load

Vessel Type	Operating Mode	Number of Vessels	Engine Load	Duration (hr)
Aframax	In transit (loaded)	1	90%	12
Aframax	In transit (unloaded)	1	60%	12
Aframax	Lightering	1	90%	12
Aframax	Docked (loading)	1	10%	12
VLCC	Lightering	1	25%	12
Tractor Tug	Mooring assist	2	100%	3

Maximum Emission Rates (lb/event)

Pollutant	Onshore tanker engines	Onshore assist tugs	Transit	Lightering
NO_x	495	789	7428	6933
CO	115	275	1726	1611
SO_2	17	40	254	237
$PM/PM_{10}/PM_{2.5}$	15	35	220	205
VOC	15	35	221	206
CO2e	54	128	804	750
HAP	0.2	0.6	3.5	3.2

Emission Factors (lb/MBbl)

Pollutant	Onshore tanker engines	Onshore assist tugs	Transit	Lightering
NO_x	0.99	1.58	14.86	13.87
CO	0.23	0.55	3.45	3.22
SO_2	0.03	0.08	0.51	0.47
$PM/PM_{10}/PM_{2.5}$	0.03	0.07	0.44	0.41
VOC	0.03	0.07	0.44	0.41
CO2e	0.11	0.26	1.61	1.50
HAP	0.0005	0.0011	0.007	0.006

Emission Rates (tpy for equivalent volume exported)

Pollutant	Onshore tanker engines	Onshore assist tugs	Transit	Lightering	Grand Total
NO_x	190	303	2852	2662	6008
CO	44	106	663	619	1431
SO_2	6	16	97	91	210
$PM/PM_{10}/PM_{2.5}$	6	13	84	79	182
VOC	6	14	85	79	183
CO2e	21	49	309	288	667
HAP	0.1	0.2	1.3	1.2	2.9

<u>Notes:</u>

1.VOC, NOx, PM, CO and SO_2 emissions are based on AP 42 section 3.4 emission factors. SO2 emission factor adjusted to account for 1000 ppmw sulfur concentration.
2. NOx emission factors for marine diesel engines based on MARPOL Annex VI emission limit.
3. Operating load and activity duration estimates explained in Sec. 13.
4. HAP emissions are the sum of AP-42 section 3.4 emission factors for Formaldehyde, Acrolein, Acetaldehyde, BTX, and total PAHs.
5. Brake-specific fuel consumption (BSFC) of marine diesel assumed to be 7000 Btu/hp-hr (AP-42 Sec. 3.3).

Supporting Calculations (Vessel Emissions for SPM Loading)
Bluewater Texas Terminal LLC

Equipment source	Number of Vessels	Pollutant	Power (hp)	Power (kw)	Speed (rpm)	Load Factor (%)	Annual Operation (hr)	Emissions Factor		Emissions per vessel	
								Value	Units	lb/hr	tpy
Work boat	2	NOx	1,500	1,119	750	25.00%	8,760	0.0158	lb/hp-hr	5.92	25.92
		CO						0.0055	lb/hp-hr	2.06	9.03
		SO_2						0.001	lb/hp-hr	0.30	1.33
		$PM/PM_{10}/PM_{2.5}$						0.0007	lb/hp-hr	0.26	1.15
		VOC						0.0007	lb/hp-hr	0.26	1.16
		CO2e						0.0026	lb/hp-hr	0.96	4.21
		HAP						0.000011	lb/hp-hr	0.004	0.02
Tug boat	2	NOx	10,000	7,457	750	25.00%	8,760	0.0158	lb/hp-hr	39.45	172.78
		CO						0.0055	lb/hp-hr	13.75	60.23
		SO_2						0.001	lb/hp-hr	2.02	8.86
		$PM/PM_{10}/PM_{2.5}$						0.0007	lb/hp-hr	1.75	7.67
		VOC						0.0007	lb/hp-hr	1.76	7.72
		CO2e						0.0026	lb/hp-hr	6.40	28.05
		HAP						0.000011	lb/hp-hr	0.03	0.12
VLCC propulsion engine	2	NOx	34,866.57	26,000	100	10.00%	8,760	0.0237	lb/hp-hr	82.54	361.52
		CO						0.0055	lb/hp-hr	19.18	83.99
		SO_2						0.001	lb/hp-hr	2.82	12.35
		$PM/PM_{10}/PM_{2.5}$						0.0007	lb/hp-hr	2.44	10.69
		VOC						0.0007	lb/hp-hr	2.46	10.77
		CO2e						0.0026	lb/hp-hr	8.93	39.12
		HAP						0.000011	lb/hp-hr	0.04	0.17

Pollutant	Total Emissions (tpy)
NO_X (VLCC)	723
NO_X (Tug and Workboat)	397
CO	307
SO_2	45
Particulate	39
VOC	39
GHG	143
HAP	0.6

Notes:
1.VOC, NOx, PM, CO and SO_2 emissions are based on AP 42 section 3.4 emission factors. SO2 emission factor adjusted to account for 1000 ppmw sulfur concentration.
2. NOx emission factors for marine diesel engines based on MARPOL Annex VI emission limit.

Supporting Calculations (Controlled and Uncontrolled Loading Emissions)
Bluewater Texas Terminal LLC

Constants

Quantity	Units	Value
Vapor Phase MW (hourly)	lb/lbmol	60.3
Vapor Phase MW (annual)	lb/lbmol	59.4
Ambient Temp. (hourly)	°F	95
Ambient Temp. (annual)	°F	72.1
Product:		Crude Oil
VP (hourly)	psia	9.32
VP (annual)	psia	6.44
Annual Throughput	MBbl/yr	384000
Pumping Rate (SPM Loading)	MBbl/hr	80
Pumping Rate (Lightering)	MBbl/hr	40
H_2S Max Vapor Concentration	ppmw	130
HAP Max Vapor Concentration	wt. %	4.4%
Control Device Destruction Efficiency	%	99%
Capture System Efficiency	%	99%
Vapor Heat Content	Btu/lb	20000
Saturation Factor		0.2
Loading Loss Factor (hourly)	lb/MBbl	106.0
Loading Loss Factor (annual)	lb/MBbl	75.3

Emission Factors

Activity	Pollutant	Hourly EF (lb/MBbl)	Annual EF (lb/MBbl)
Uncontrolled Loading	VOC	106.0	75.3
Uncontrolled Loading	HAP	4.7	3.3
Uncontrolled Loading	H_2S	0.014	0.010
Dockside Loading (Uncaptured Emissions)	VOC	1.060	0.753
Dockside Loading (Uncaptured Emissions)	HAP	0.047	0.033
Dockside Loading (Uncaptured Emissions)	H_2S	0.00014	0.00010
Dockside Loading (Controlled)	VOC	1.050	0.745
Dockside Loading (Controlled)	HAP	0.046	0.033
Dockside Loading (Controlled)	SO_2	0.026	0.018

Activity	Pollutant	EF (lb/MMBtu)	Units
Dockside Loading (Controlled)	NO_X	0.1	lb/MMBtu
Dockside Loading (Controlled)	CO	0.074	lb/MMBtu
Dockside Loading (Controlled)	Particulate	0.0075	lb/MMBtu
Dockside Loading (Controlled)	GHG	117.6	lb/MMBtu

Activity	Pollutant	Emission Rate (lb/hr)	Emission Rate (tpy)
SPM Loading (Uncontrolled)	VOC	8483.71	14455.96
SPM Loading (Uncontrolled)	HAP	373.28	636.06
SPM Loading (Uncontrolled)	H_2S	1.10	1.88
Lightering (Uncontrolled)	VOC	4241.86	14455.96
Lightering (Uncontrolled)	HAP	186.64	636.06
Lightering (Uncontrolled)	H_2S	0.55	1.88
Dockside Loading (Uncaptured Emissions)	VOC	42.42	144.56
Dockside Loading (Uncaptured Emissions)	HAP	1.87	6.36
Dockside Loading (Uncaptured Emissions)	H_2S	0.01	0.02
Dockside Loading (Controlled)	VOC	41.99	143.11
Dockside Loading (Controlled)	HAP	1.85	6.30
Dockside Loading (Controlled)	SO_2	1.04	3.54
Dockside Loading (Controlled)	NO_X	8.40	28.62
Dockside Loading (Controlled)	CO	6.22	21.18
Dockside Loading (Controlled)	Particulate	0.63	2.15
Dockside Loading (Controlled)	GHG	9877.1	33660

Notes:
1. NO_X and VOC Emission Factors Explained in Sec. 13
2. H_2S Emission Factor Explained in Appendix Z (PSD Application)
3. SO_2 Emission Factor Based on Complete Combustion of H_2S in Waste Stream
4. Particulate and GHG Emission Factors from AP-42 Sec. 1.4
5. CO Emission Factor Based on 100 ppmv (3% O_2 reference), based on typical TCEQ BACT requirements.
6. VOC emission factor based on hydrocarbon vapor pressure from speciation analysis

Item 11

Attachment 5 [pp. 97–135] to the response provides analytical data for five crude oil samples asserted to be representative of the variety of crude oils that BWTX intends to export. Also included was an explanation of how analytical data (boiling curve, liquid phase hydrocarbon analysis, and specific gravity of cuts) were used to estimate the composition of the vapors in equilibrium with a given liquid sample. The samples were referred to generically as “Sample 1”, “Sample 2”, etc.

There are only two types of crude oil that BWTX presently plans to handle: West Texas Intermediate (WTI) and WTI Light. These were captured in the variety of samples chosen. In order to ensure that worst-case conditions were identified, BWTX additionally included samples representing crude oils from three other geologic formations, Eagle Ford, Bakken, and Powder River, the first two of which tend to have higher vapor pressures. These may be handled occasionally. The highest calculated vapor phase HAP mass fraction corresponds to WTI-Light.

Sample Number	Description
1	Eagle Ford
2	Powder River
3	WTI
4	Bakken
5	WTI-Light

Items 13–14

Proposed emission limitations and monitoring requirements are in pp. Attachment 3 [pp. 32–37] to the response. They are repeated below for ease of reference. BWTX also proposes the following requirement to supplement the proposed leak detection and repair program: “*All lines and connectors shall be visually inspected for any defects prior to hookup. Lines and connectors that are visibly damaged shall be removed from service. Operations shall cease immediately upon detection of any liquid leaking from the lines or connections.*”

A. MACT Emission Limitation

1. Liquids loaded into the cargo tanks of transport vessels shall be limited to crude oil, pipeline interface (transmix), and water. For purposes of this notice, “crude oil” shall include lease condensate.
2. The above stated owner or operator shall not permit any vessel to be loaded unless it complies with the equipment design specifications of 46 CFR § 153.282.

3. The above stated owner or operator shall not permit any vessel to be loaded unless it possesses and implements a VOC management plan consistent with the requirements specified in 40 CFR § 1043.100(b)(1), Regulation 15.6.
4. The above stated owner or operator shall conduct transfer operations in accordance with an operations manual pursuant to 33 CFR § 150.425.
5. During the initial stages of loading into each individual tank the flow rate in its branch line should not exceed a linear velocity of 1 metre/second. When the bottom structure is covered and after all splashing and surface turbulence has ceased, the rate can be increased to the lesser of the ship or shore pipeline and pumping system maximum flow rates, consistent with proper control of the system. Prior to the start of each transfer operations, the above stated owner or operator shall perform a calculation to determine the maximum cargo pumping rate which ensures compliance with this provision.
6. Each manifold flange shall be equipped with a removable blank flange. The end of each hose not connected for the transfer of oil shall be blanked off. Each part of the transfer system not necessary for the transfer operation shall be securely blanked or shut off. Prior to the removal of blanks from tanker and facility pipelines or hoses, the section between the last valve and blank shall not contain oil under pressure. Precautions to prevent spillage, including inventorying hoses with sea water at the conclusion of each loading operation, shall be implemented.

B. Monitoring Requirements

1. During each loading operation, the above stated owner or operator shall continuously monitor the transfer rate.
2. Prior to receiving a vessel at the facility, the above stated owner or operator shall conduct vetting of the vessel using a standardized vetting policy. The vetting policy shall include provisions to ensure compliance with Provisions B.2 and B.3 of this authorization.
3. The above stated owner or operator shall determine concentration of each species of HAP contained in the hydrocarbon vapors in equilibrium with the liquid phase of each grade of crude oil loaded using one of the following methods:

   (a) EPA Test Method 18 (40 CFR Part 60, Appendix A-6); or

(b) Detailed Hydrocarbon Analysis (ASTM D7169) and vapor-liquid equillibrium calculation.

Crude oil samples shall be taken from the final storage location prior to delivery to the loading facility. Sampling shall be conducted on an annual basis. For purposes of this provision, two samples of crude oil correspond to different grades if they are produced from distinct regions identified in the U.S. Energy Information Administration Drilling Productivity Report.

4. The above stated owner or operator shall, on a monthly basis, calculate the estimated HAP emissions from crude oil loading operations during the preceding 12-month period. Emissions estimates and emission factors shall be based on test data, or if test data is not available, shall be based on measurement or estimating techniques generally accepted in industry practice for operating conditions at the source.

C. Reporting and Recordkeeping Requirements

1. The above stated owner or operator shall notify EPA Region 6 in writing or by electronic mail of the following activities. Such notifications shall be delivered or postmarked within 30 calendar days after the date the activity takes place:

   (a) the actual date construction is commenced;

   (b) the actual date construction is completed; and

   (c) the actual date of startup of the source.

2. Records containing the information and data sufficient to demonstrate compliance with the provisions of this approval shall be maintained at an office having day-to-day operational control of the site. Such records shall be maintained for at least five years following the date the information or data is obtained.

3. The above stated owner or operator shall maintain the following records:

   (a) A copy of the operational manual required under Provision B.4.

   (b) A copy of the vetting policy required under Provision C.2.

4. The above stated owner or operator shall maintain a file which specifies, for each crude oil loading operation, the following information:

   (a) The volume of crude oil loaded;

   (b) The true vapor pressure of the crude oil loaded;

(c) The date and time of commencement and completion of the loading operation;

(d) The date and time at which submerged fill is established; and the calculated maximum allowable pumping rate and actual cargo transfer during the time period specified in Provision B.5.

(e) The results of the vetting of the vessel, to the extent necessary to establish compliance with Provision C.2.

(f) The estimated quantity of HAP emissions resulting from the loading operation;

(g) The identifier of the mooring buoy at which loading takes place (i.e., SPM1 or SPM2);

(h) The IMO registry number corresponding to the loaded vessel;

D. Other Requirements

1. The above stated owner or operator shall comply with the startup, shutdown and malfunction (SSM) plan requirements specified at 40 CFR § 63.6(e).
2. At all times, including periods of startup, shutdown, and maintenance, the above stated owner or operator shall, to the extent practicable, maintain and operate the facility including any associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.
3. The requirements of this notice shall be administratively incorporated into the facility's Title V operating permit (40 CFR Part 71) upon issuance of such operating permit.
4. Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified.
5. EPA authorized representatives, upon the presentation of credentials, shall be permitted to undertake the following actions:

(a) Enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this notice;

(b) During normal business hours, have access to and make copies of any records required to be kept under the terms and conditions of this notice;

(c) Inspect any equipment, operation, or method subject to requirements in this notice; and

(d) Sample materials and emissions from the sources.

6. In the event of any changes in control or ownership of the facilities to be constructed, this notice shall be binding on all subsequent owners and operators. The above stated owner or operator shall notify the succeeding owner and operator of the existence of this notice and its conditions by letter; and a copy of the letter shall be forwarded to EPA Region 6 within thirty days of its signature.

7. The provisions of this notice are severable, and, if any provision of this notice is held invalid, the remainder of this notice shall not be affected.